Drill string design, drilling techniques impact wear

Roy L Dudman and Rick A Dudman
PinTec Services Inc

GOOD DRILLING TECHNIQUES and proven drillstring design can prevent excessive casing, wellhead and riser wear and limit drill pipe wear and fatigue. The following guidelines can help extend drillstring life and avoid problems:

- Stop unnecessary reaming and back reaming with highly tensioned drillstrings because the correct bottomhole assembly (BHA) continuously reams the hole being drilled;

- Limit BHA weight to required bit weight plus an appropriate safety factor as recommended for near vertical holes because a tensioned drillstring in crooked holes causes drill pipe wear and fatigue in addition to wear on the casing, wellhead and riser;

- Reduce rotary speed (RPM) to near zero when lifting the drillstring because wear, fatigue and harmful bending cycles are excessive at high RPM;

- Limit lifting of the bit from the bottom of the hole as this insures minimum tension/side loading of the drillstring and drilling ahead continues to ream the hole;

- Plan wellbore path with angle changes as near to total depth as possible since drillstring tension is minimal near TD.

REAMING, BACK REAMING

From the findings of **Arthur Lubinski**, **Moak Rollins**—and more recently through DEA investigations—it is common knowledge that un-hardbanded ("slick") and tungsten-carbide based hardbanded tool joints alike cause wear problems on drill strings and in casing. This situation is not addressed daily even though proven drilling techniques can readily mitigate and frequently resolve the problem.

The primary operational culprits are reaming and back reaming.

Reaming dates back to the days of fishtail bits run in conjunction with limber drill collars and no stabilization. Back reaming is generally associated with the introduction of the top drive drilling system. Both reaming and back reaming are essential for removing tight spots in the well bore.

Unfortunately, reaming and back reaming contribute significantly to wear problems of drill pipe, casing, wellheads and risers. A closer evaluation of potential wear problems associated with a particular wellbore profile could easily lead to a different wellbore design that would lessen destructive wear damages.

"Optimization of the drillstring for a given wellbore path is a relatively easy approach that consistently results in improved performance and reduced wear on all drilling components."

Computer modeling of drillstrings in a planned wellbore path will quickly show potential problem areas.

Frequently, minor hole angle changes in conjunction with any available depth changes will result in dramatically lower destructive side loading of both the drillstring and the casing.

Reciprocating a drill string in tension at elevated rotational speeds in crooked holes generates very high side loading and accelerates wear. This problem is magnified when well bore deviation occurs at shallow depths.

Deviation of the well bore near total depth is not nearly as detrimental since shallow doglegs exert much higher loading on a drillstring.

CORRECT BHA DESIGN

To minimize deviated well bores, especially at shallow depths, the correct bottomhole assembly (BHA) should be used.

The smoother the wellbore profile the lower the side loading forces will be.

Obviously, not all wellbores can have the ideal near-vertical profile, but longer, straighter tangents in planned directional holes will greatly decrease tubular side loading. Designing a BHA that incorporates the minimum weight required, thereby minimizing tension loads on the drillstring, will further minimize side loading.

A short drill collar "lock-in" assembly with heavy wall drill pipe for the required bit weight limits the tension in the drillstring.

In high angle well bores, a certain amount of drill pipe can be run in compression for bit weight to further limit the weight of the BHA and subsequent tension in the drillstring. Where feasible, drilling to deeper depths prior to departure will help minimize drillstring side loading.

With the advancements available in steerable navigational systems, wellbore path trajectories can frequently be changed at greater depths while still insuring arrival at the desired target.

Figure 1: Operational life*

Conventional			Pinup		
TJ OD	MUT	Status	TJ OD	MUT	Status
7 1/8 in.	55,800	Full	7 1/2 in.	55,800	Full
7 in.	53,800	Reduced	7 3/8 in.	55,800	Full
6 7/8 in.	48,500	Reduced	7 2/8 in.	55,800	Full
6 3/4 in.	44,000	Reduced	7 1/8 in.	55,800	Full
			7 in	53,000	Reduced
			6 7/8 in.	48,500	Reduced
			6 3/4 in.	44,000	Reduced

*5 1/2-in. HT operational life
7 1/8-in. OD x 3 3/4-in. ID

Longer life 100%, longer full MUT, no rig changeout.

HARDBANDING

Historically, solutions for drillstring and casing wear problems have been addressed through the application of hardbanding.

Tungsten carbide hardbanding has generally been accepted as the most effective and least costly approach to limiting drillstring wear.

The tradeoff for prolonged drillstring life through the use of tungsten carbide hardbanding is accelerated casing wear. The development of casing "friendly" hardbanding significantly improved casing wear problems but did so at the expense of the drillstring components.

The proverbial situation of being between a rock and a hard place applies not only to the equipment but also to the difference between drilling contractor and operator concerns. What helps one hurts the other and vice-versa.

Until technology develops a cost-effective substance that is readily applied that can truly protect the drillstring and still be casing friendly, the logical approach is to pursue drilling technologies, including wellbore trajectory planning.

Providing the least harmful wellbore design will not only enhance tubular protection and casing life but it will also maximize the benefits of current hardbanding technology and allow both approaches to complement one another.

DRILLSTRING DESIGN

In addition to planning a wellbore trajectory that will limit drillstring wear and damages, the selection of a drillstring design that is resistant to wear and damages is equally important.

Larger, stronger drillstrings prevent the accumulation of fatigue, increase hydraulic parameters and control hole deviation problems.

A typical problem begins in BHA design based on the use of 8-in. OD drill collars with 6⅝-in. regular connections; these have not been "API" for 40 years.

This begs the question: Why do we still run 8-in. drill collars in 12¼-in. hole sections?

Sufficient 9½-in. OD or larger drill collars for bit weight plus a 15% margin has proven to virtually eliminate connection failures and provide far superior deviation control and weight concentration directly above the bit.

One stand of 8-in. OD or preferably API 8¼-in. OD drill collars should be run in tension in the destructive transition zone with long (5-ft) bottleneck crossover subs between the drill collars (9½-in. OD to 8¼-in. OD) and between the drill collars and heavy wall drill pipe (8¼-in. OD drill collars to 5-in. heavy wall pipe).

The use of larger stronger drillstring components in smaller hole sizes has also prevented the accumulation of fatigue, improved hydraulics and controlled deviation.

These stronger drill strings have been successfully run in 4¾ in. and larger

Figure 2: Pin up drill strings compared

Hole size	Conventional drill pipe	Pin up drill pipe	Increase
	3 1/2-in., 13.3#, NC-38 tool joints 4 3/4-in., OD x 2 11/16-in. ID	4-in., 14.0#, NC-40 tool joints 5 3/8-in. OD x 2 11/16-in. ID, 4 7/8-in. pin	
	Torsional: 14,361/10,367 ft lb	Torsional: 18,196/15,283 ft lb	+25/+43%
	Tensile: 271,569/589,308 lb	Tensile: 285,359/776,406 lb	+5/+32%
6 in. through 6 3/4 in.	Tube ID: 2.764 in.	Tube ID: 3.340 in.	+0.576 in.
	4-in., 14.0#, slim hole, 3 1/2 in. XH tool jts 4 5/8-in. OD x 2 9/16-in. ID	4-in., 14.0#, NC-40 tool joints 5 3/8-in. ODx 2 11/16-in. ID, 4 7/8-in. OD pin	4-in. slim hole vs 4-in. Pin-up
	Torsional: 18,196/13,273 ft lb	Torsional: 18,196/15,283 ft lb	+0/+15%
	Tensile: 285,359/525,637 lb	Tensile: 285,359/776,406 lb	+0/+47%
	Tube ID: 3.340 in.	Tube ID: 3.340 in.	

hole sizes, including 5¾-5⅞ in., 6-6½ in., 7⅝-7⅞ in., 8⅜-8¾ in., 9⅞ in. and 10⅝ in. In all cases, significant increases in rates of penetration (ROP) were achieved, deviation was controlled and repairs due to damage were reduced. Specific examples include:

• The use of 4⅛-in. OD drill collars and 3½-in. Slim Hole drill pipe in 4¾-in. and 4⅞-in. hole sections. Tubulars with 4⅛-in. OD box by 3¹³⁄₁₆-in. OD pin up connections have prolonged tool joint life and improved hydraulics by using a larger bore 3½-in. tube;

• The use of 5-in. OD drill collars, 3½-in. heavy wall drill pipe and 3½-in. drill pipe with 4¾-in. OD box by 4½-in. OD pin up connections in 5⅞-in. hole sections;

• The use of 5¼-in. OD drill collars, 4-in. heavy wall drill pipe and 4-in. drill pipe with 5¼-in. OD box by 4⅞-in. OD pin up connections in 6-6½-in. hole sections. Fishability is retained, hydraulics are improved, ROPs are increased, deviation control is achieved and tool joint wear life is appreciably increased;

• The use of 7-in. OD drill collars, with fishable pin dimensions have been repeatedly used in 7⅞-in. hole sections for added weight on bit and deviation control. Ideally, 5-in. heavy wall drill pipe and 5-in. drill pipe with 6⅜-6½-in. OD box by fishable dimensioned pin up connections would significantly lower costs through improved performance;

• The use of 7¾-in. OD drill collars with fishable pin areas in 8⅜-8½-in. hole sizes and ideally 5½-in. heavy wall drill pipe and 5½-in. drill pipe, both with fishable pin dimensions. In addition to substantial deviation control, hydraulic parameters and drillstring service life are increased.

In addition to these benefits, particularly with the 5½-in. tubulars, tool joint service life and full make up torque (MUT) life may be appreciably increased.

Box OD and pin ID are the primary dimensions controlling joint strength. Large box ODs maintain maximum tool joint strength and provide a longer service life.

Smaller, fishable box ODs compromise connection strength and tool joint service life (Figure 1).

In the case of 5½-in. drill pipe with 7-in. OD box connections, the drill pipe has a minimum 6¹⁵⁄₁₆-in. OD for Premium Class rating or just ¹⁄₁₆ in. of OD wear!

Starting with a 7½-in. OD box would increase wear life to ⁹⁄₁₆ in. for multiple life cycle extensions and multiple full make up torque cycles.

At 6¾-in. OD, standard 5½-in. drill pipe must be replaced (or re-built if permitted). But if one had started with a 7½-in. OD box connection, a full 7-in. OD would remain, or essentially a whole wear life.

In addition, as the 7½-in. OD connection wore down, complete full make up torque remained in force, whereas the standard connection was continually downgraded in make up torque values.

5½-in. drill pipe with a 3½-in. bore and 7-in. OD box would be box weak, thus experiencing a reduction in strength and make up torque. The 7½-in. OD box would not have any reduction in torsional strength until worn to 7⅛-in. OD.

Box strong connections provide a longer service life. Large box connections and fishable pin tool joints insure a long service life for standard API connections as well as for premium double shouldered and wedge thread connections.

Large drill collars provide weight and stiffness in the packed bottom hole assembly (BHA) and pendulum BHA designs provide for maximum control of hole deviation.

Strong box connections also insure against developing fatigue cracks and premature failures. An industry wide report on drillstring failures would surely be shocking as to the total of preventable failures.

Unscheduled events including washouts, unnecessary tripping for premature repairs and inspections, crooked hole problems, slow penetration rates and shortened service life could all be minimized if not virtually eliminated by simply using larger, stronger more efficient drillstring designs based on proven technology.

Optimization of the drillstring for a given wellbore path is a relatively easy approach that consistently results in improved performance and reduced wear on all drilling components. ■